Decision **PROPOSED DECISION OF ALJ HYMES** (Mailed 12/31/2012)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Aggregator Managed Demand Response Agreements (U39E).	Application 12-09-004 (Filed September 7, 2012)
And Related Matter.	Application 12-09-007

DECISION GRANTING APPLICATIONS FOR DEMAND RESPONSE AGGREGATOR MANAGED PORTFOLIO AGREEMENTS

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DECISION GRANTING APPLICATIONS FOR DEMAND RESPONSE AGGREGATOR MANAGED PORTFOLIO AGREEMENTS

1. Summary

This decision approves five demand response aggregator managed portfolio program agreements and budgets requested by Southern California Edison Company (SCE) and five agreements requested by Pacific Gas and Electric Company (PG&E). In order to ensure that ratepayer funds are properly utilized and to ensure the reliability of the demand response resources from these agreements, we require both utilities to annually implement a demand response test event early in the season, but no later than May 31, and, if a non-test event is not called by July 15, at least one additional test event during the months of July or August. We clarify that a test event held by a demand response aggregator, also known as a Seller, complies with this requirement if the associated utility receives the results of the test.

SCE must file a Tier 1 Advice Letter revising its Demand Bidding Program tariff to ensure that customers dually enrolled in the Demand Bidding Program and an Aggregator program receive compensation for events solely from the Aggregator program.

SCE is authorized a budget of up to $49.3 million to be recovered through the same ratemaking methodology as that approved in the current agreements. PG&E is authorized to recover costs for these agreements through its Energy Resource Recovery Account, as previously requested in Application (A.) 12-06-002.

A.12-09-004 and A.12-09-007 are closed.

2. History of Aggregator Managed Portfolio (AMP) Agreements

In the wake of the 2006 California heat storm, the Commission requested Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) to increase its demand response resources in order to improve grid reliability. Demand response is a reduction or shift in electricity consumption by customers in response to either economic or reliability signals.

In Decision (D.) 06-11-049, the Commission authorized PG&E to allow third-party demand response providers, also known as aggregators, to participate in the Base Interruptible Program. The Commission also directed SCE to permit such participation in its program. Subsequently, the Commission approved multi-year aggregator agreements for PG&E for years 2007 through 2011 and SCE for years 2007 through 2008.[1] In 2008, the Commission authorized SCE to enter in to four new agreements, one of which expired at the end of 2011 and three of which expire at the end of 2012.[2] In D.09-08-027, the Commission approved a settlement agreement for two additional contracts, one between SCE and EnerNOC, Inc. (EnerNOC) and one between SCE and Comverge, Inc. (Comverge).

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[1] In D.07-05-029, the Commission authorized PG&E to enter into five-year agreements with demand response aggregators that would provide between 35 megawatts (MW) and 46 MW of demand response by August 2007, between 107 MW and 129 MW by August 2008, and between 132 MW and 149 MW in 2009 to 2011. The Commission also authorized SCE to enter into a two-year agreement with a demand response aggregator, lasting from 2007 until 2008 that would provide up to 40 MW of demand response capacity by June 2008.

[2] D.08-03-017 at Ordering Paragraph (OP) 2.

In applications for approval of demand response programs and budgets for years 2012-2014, Application (A.) 11-03-001 et al., PG&E requested the Commission to extend the current five AMP agreements for one additional year and to allow PG&E to issue a request for offers for new agreements. In D.12-04-045, the Commission found those AMP agreements to be valuable, but not cost-effective as proposed. The Commission directed PG&E to either negotiate extensions to the existing five agreements approved in D.07-05-029 or conduct a solicitation for new agreements for years 2013-2014. The Commission provided SCE with the same two options. For either renegotiated or newly solicited agreements, the Commission required PG&E and SCE to: 1) ensure that the Total Resource Cost (TRC)[3] tests attain at least a 0.9; and 2) maintain demand response resources equal to or greater than current AMP agreements (280 MW for SCE and 180 MW for PG&E.)

3. Procedural Background

On September 7, 2012 PG&E filed A.12-09-004 seeking approval of five demand response AMP agreements and SCE filed A.12-09-007 also seeking approval of five AMP agreements. On September 14, 2012, SCE filed a Motion to Shorten Time to Respond to the Applications. The assigned Administrative Law Judge (ALJ) issued a Ruling on September 28, 2012 denying SCE's Motion and consolidating the two applications.

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[3] The TRC test is the cost-effectiveness test chosen by the Commission in D.12-04-045 to ultimately determine whether a demand response program is considered cost-effective. Until further notice, a result ratio of at least 0.9 is required to consider a demand response program cost-effective.

The Division of Ratepayer Advocates (DRA) filed a timely protest to the applications on October 14, 2012. Energy Curtailment Specialists, Inc. (ECS) and a coalition of demand response aggregators each filed a timely response supporting the two applications.

On November 5, 2012, the assigned ALJ held a Prehearing Conference (PHC) to determine the parties, scope, and schedule as well as other procedural matters.

On November 9, 2012, DRA filed a Motion to Withdraw its protest of the SCE application, explaining that they had resolved the concerns with the SCE application. Subsequently, the assigned Commissioner and ALJ jointly filed a Ruling and Scoping Memo (Scoping Memo) setting the scope of the issues as discussed below, granting DRA's Motion to Withdraw, and establishing a shortened review and comment period of seven days for this proposed decision with no reply comments.[4]

Parties filed opening briefs on November 28, 2012 and reply briefs on December 5, 2012. The assigned ALJ submitted the record of this proceeding on December 31, 2012.

4. Issues

As discussed during the PHC and determined in the Scoping Memo, the issues to be addressed in this proceeding are as follows: a review of the AMP Agreements and the associated budgets, whether the agreements meet resource adequacy requirements, cost recovery issues, and whether the Commission

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[4] Joint Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo issued November 13, 2012. *See* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K723/31723598.PDF

should authorize SCE to file a Tier Three Advice Letter (AL) to propose changes to the agreements, if necessary, to mitigate impacts resulting from the current outage at the San Onofre Nuclear Generating Station (SONGS).

The review of the AMP agreements will focus on ensuring compliance with D.12-04-045, including compliance with other related Commission decisions; whether the agreements are reasonable, especially with regard to Pub. Util. Code § 451; and whether the agreements are required to meet future needs.

5. Overview of AMP Agreements

5.1. PG&E Agreements[5]

PG&E requests approval of five AMP agreements whereby each contractor or Seller[6] agrees to deliver a specified amount of demand response energy and capacity to PG&E during the months of May through October in 2013 and 2014 when a demand response event is triggered. PG&E also requests that the costs of these agreements[7] be recovered through the Energy Resource Recovery Account (ERRA) as has been the case with prior AMP agreements and other demand response programs.[8]

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[5] Unless otherwise noted, the stated facts in this section of the decision can be found in PGE-01, Chapters 1 and 3.

[6] The agreements are with Constellation New Energy (Constellation), ECS, Energy Connect, Comverge, and EnerNoc, who are referred to collectively as the Sellers.

[7] PG&E filed A.12-06-002 forecasting to recover $16.2 million in AMP agreement payments during 2013. Since filing the 2013 ERRA application, PG&E entered into these new agreements, which provide increased load reductions resulting in AMP agreement payments of $19.9 million. PG&E states that it updated A.12-06-002 to reflect this difference. *See* PGE-01 at 5-1.

[8] D.07-06-029 authorized the recovery of AMP agreement payments through ERRA. D.12-04-045 maintains the recovery of AMP agreement payments via ERRA. *See* PGE-01 at 5-1.

The agreements provide three different demand response products: Day-Of, Day-Of with Local Dispatch, and Day-Ahead with Local Dispatch. A total of seven products collectively will provide approximately 248.5 MW of demand response capacity in 2013 and 267 MW of demand response capacity in 2014. Five of the products allow PG&E to dispatch the demand response resources on a locational basis using the California Independent System Operator (CAISO) Local Capacity Areas (LCAs). The demand response for these agreements will be provided by electric customers in the PG&E service area who have contracts with the Sellers. The following table summarizes the commitment level for these products.

TABLE 1
PG&E AMP Contracts
Commitment Level by Demand Response Product

Product Type	2013 Commitment Level	2014 Commitment Level
Day-Of[9] (2)	53.0	59.0
Day-Of with Local Dispatch (3)	110.5	123.0
Day-Ahead with Local Dispatch[10] (2)	85.0	85.0
Total Commitment Level	248.5	267.0

The proposed agreements require the Sellers to make the products available for demand response events Monday through Friday between the hours of noon to 7:00 p.m., excluding holidays. The agreements establish that an event may be triggered whenever PG&E anticipates the dispatch of electric

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9 Day-Of products have a notification period of at least 30 minutes.

10 Day-Ahead products have a notification period of no later than 3:00 p.m. the prior day.

supply resources with implied heat rates of 15,000 British thermal units per kilowatt-hour or greater, and/or when PG&E, in its sole discretion, anticipates conditions or situations that may impact the electric system. An event, however, is limited to four to six hours per day. In addition to demand response events, PG&E may call up to two test events in each of the two contract years. The agreements limit the total hours each product may be dispatched to no more than 80 hours per product per year, including test events.

Sellers are compensated during each delivery month for providing a product if a demand response event is called in that month (Monthly Performance Payment) and for making the commitment level available each month (Monthly Capacity Payment.)

During months with no events, the Seller will receive only the Monthly Capacity Payment. That payment is equal to the Monthly Capacity Price (product of the Seller's Annual Capacity Price[11] multiplied by the Monthly Capacity Price Factor[12]) multiplied by the system wide commitment level.

During months when an event is called, inclusive of test events, the Seller will receive a Monthly Capacity Payment that is based upon performance. The Seller's performance is determined by the Hourly Capacity Ratio and the Hourly Capacity Price where the Hourly Capacity Price equals the Monthly Capacity Price divided by the number of event hours for that month and the Hourly

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11 Each Seller provided an annual capacity price in dollars per kilowatt (kW) per year as part of its bid. The annual capacity price is confidential.

12 A determiner of the Monthly Capacity Price, the Monthly Capacity Price Factor adjusts for when a demand response project is expected to be more valuable. The Monthly Capacity Price Factor is 0.05 for May, 0.06 for June, 0.26 for July, 0.36 for August, 0.23 for September, and 0.04 for October, totaling 100 percent for the season.

Capacity Ratio equals the Seller's Performance level divided by the Seller's Commitment Level. *See* Table 2 for more details.

TABLE 2 PG&E Hourly Capacity Payment Provided During Months with Events	
Hourly Capacity Ratio (Performance Level / Commitment Level)	**Hourly Capacity Payment Calculation**
1.00	Hourly Capacity Price (=Monthly Capacity Price / # hours)
.90 to .99	Hourly Capacity Price x Hourly Capacity Ratio
.74 to .89	Hourly Capacity Price x 0.50
.50 to .74	0
0 to .49	**PENALTY PAID TO PG&E** Hourly Capacity Price x (Hourly Capacity Ratio -0.50)

A Seller is compensated for good performance, but penalized for underperforming. For example, if a Seller performs at 100 percent, the Seller receives the full Hourly Capacity Price for each hour of that event. However, if a Seller performs at only 90 percent, they would receive the Hourly Capacity Price multiplied by 0.9. Furthermore, if a Seller performs at 30 percent, the Seller must pay PG&E a penalty equal to the Hourly Capacity Price multiplied by 0.80.

For locally dispatched demand response products, the Monthly Capacity Payment is equal to the sum of the payments (as calculated in Table 2) for each LCA that gets dispatched. For LCAs not dispatched during that month, the Seller receives a payment equal to the Monthly Capacity Price multiplied by the Commitment Level for the LCA.

During months in which a demand response event is called, the Seller will also receive a Monthly Performance Payment equal to the Locational Marginal Price multiplied by the number of demand response event hours for that month. A Seller is not compensated for Performance exceeding 150 percent of the Commitment Level.

In addition to the elements described above, the five PG&E agreements include protections for PG&E customers, including protections related to the security and confidentiality of customer data. The agreements also give PG&E the exclusive rights to the Resource Adequacy[13] from all demand response products.

5.2. SCE Agreements[14]

SCE requests approval of four Day-Of[15] agreements and one Day-Ahead[16] agreement with a total commitment level of 296 MW of cost-effective third-party demand response capabilities. The contractors or Sellers for SCE are EnerNOC, Constellation, North American Power Partners (NAPP), Energy Connect and ECS. SCE also requests recovery of $49.9 million of revenue requirement during years 2013-2014.

The SCE agreements commence January 1, 2013, or upon approval by the Commission, and are effective until December 31, 2014. The five agreements are uniform in terms except for "inputs that affect each one's cost-effectiveness results, namely, months and hours of availability, size of the program in MW, capacity and energy price terms, and a difference in the dual participation rule between Day-Of and Day-Ahead [agreements.]"[17] While the exact commitment

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[13] Resource Adequacy provides sufficient resources to the CAISO to ensure the safe and reliable operation of the grid in real time.

[14] Unless otherwise noted, the stated facts in this section of the decision can be found in Exhibit SCE-01.

[15] Dispatched on one-hour's notice.

[16] Dispatched by 3:00 p.m. on the day before it is needed.

[17] SCE-01 at 10.

level for each month is confidential, the levels "typically increase during the critical summer months and decrease during the less critical winter months."[18]

The agreements establish that SCE has the sole discretion of when a demand response event is triggered. Consistent with the CAISO market, the agreements also provide that SCE may dispatch the demand response resources by Sub-Load Aggregation Point when transmission or distribution circuits are constrained, or when the price of energy at that particular Point is high. A new addition to SCE's price-responsive programs, four of the agreements provide more flexibility in dispatch since they may be dispatched on just a one-hour notice.

Under the terms of the agreements, the Sellers will be compensated on two levels, a Monthly Capacity Payment for making the demand reduction available and a Monthly Energy Payment for reduced energy consumption from bundled service customers[19] during dispatch events or SCE test events. The Monthly Capacity Payment is adjusted based on the results of dispatch or test events so that if performance is less than 100 percent, the delivered capacity payment is prorated. Furthermore, for performance less than 90 percent but at least 75 percent, Sellers will only receive one-half the capacity credit rate and for performance less than 75 percent, Sellers will not receive a payment. The Monthly Energy Payment provides payment for reduced energy consumption by bundled service customers during an event (either a dispatch or test event). For performance less than 100 percent, Sellers are billed for shortfall energy. For

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[18] SCE-01 at 11.

[19] Utility customers who receive their routine electric service from SCE.

performance between 100 and 150 percent, Sellers are paid the contracted energy payment.

The agreements provide that SCE may call for as many test events as it sees reasonable. Furthermore, if a Seller increases its availability during a month when SCE did not call an event, the agreements provide that the Seller must prove that it can provide that increased amount by holding a Buyer-directed test.

According to SCE, the agreements are consistent with Commission-approved dual participation rules[20] and baseline/settlement procedures.[21] However, the agreements also take into consideration that not all demand response issues have been resolved, especially those related to direct participation. Thus, the agreements provide that the Sellers and SCE commit to negotiate in good faith to consider amendments to the agreements consistent with final demand response direct participation rules.

6. Review of AMP Agreements and the Associated Budgets

6.1. Compliance with D.12-04-045

6.1.1. Compliance with OPs 15 & 16

6.1.1.1. Parties' Positions

Both PG&E and SCE state that D.12-04-045 orders two requirements of the utilities regarding AMP agreements. First, each utility should either renegotiate current agreements or conduct competitive bidding solicitations for new agreements equaling a minimum of 180 MW for PG&E and 280 MW for SCE. Second, for either option, the TRC test benefit/cost ratio shall attain at least a 0.9

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[20] The dual participation rules are outlined in D.12-04-045 at 47-56.

[21] The baseline refers to the Aggregated Energy Baseline, which is the average interval data of the 10 similar days prior to the called event. The interval data is the hourly summation of the load of the Service Agreements in a Seller's portfolio.

for each individual agreement. PG&E and SCE submit that all of the requested agreements meet the requirements of D.12-04-045. All other parties to this proceeding agree that PG&E and SCE have complied with these two requirements.

6.1.1.2. Discussion

In the Commission's review of the contracts, we have found that both PG&E and SCE have met the first part of OPs 15 and 16 of D.12-04-045: to either negotiate current AMP agreements or conduct competitive solicitations for new agreements at the required capacity floor. Both utilities decided to conduct competitive solicitations for new agreements. No party protested the competitive process used by either utility. In reviewing the procedures taken, we find the solicitation procedures followed by both PG&E and SCE to be appropriately competitive. We further acknowledge that both utilities heeded our encouragement to seek additional capacity beyond the required floors, with PG&E proposing agreements for 248.5 MW in 2013 and 247 MW in 2014 and SCE proposing agreements for 239 MW in 2013 and 296 MW in 2014.

Commission staff reviewed the cost-effectiveness results of each agreement and found that PG&E and SCE complied with the cost-effectiveness protocols first developed in D.10-12-024 and revised in D.12-04-045; each agreement attained a TRC test benefit/cost ratio of 0.9 or greater. Thus, the agreements meet the second part of OPs 15 and 16. We conclude that the 10 agreements requested by PG&E and SCE meet the requirements of OPs 15 and 16 of D.12-04-045.

6.1.2. Compliance Beyond OPs 15 & 16

6.1.2.1. Parties' Positions

Demand Response Aggregators[22] claim that the requirements of OPs 15 and 16 are the sole requirements for this application. DRA contends that taking such an "approach would run afoul of the Commission's obligation to review utility contracts under Pub. Util. Code § 451,"[23] which states that charges requested by any public utility for any service provided shall be just and reasonable. DRA argues that the applications should be reviewed beyond the requirements of OPs 15 [and 16] and "to do so otherwise would render this application process a ministerial filing."[24]

Demand Response Aggregators contend, "any program or action authorized in D.12-04-045 has been subject to the broadest and greatest scrutiny possible."[25] They state "only after and upon a full review of all applicable policies, precedent, and the record that the Commission in D.12-04-045 approved solicitations by PG&E and SCE for new AMP contracts."[26] Demand Response Aggregators further argue that the Commission has already considered reasonableness, the need to maintain current demand response resources, performance and cost-effectiveness of AMP contracts, and meeting future needs.[27]

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[22] Demand Response Aggregators include EnerNOC, Inc., Johnson Controls, Inc., and Comverge.

[23] Opening Brief of DRA at 5.

[24] Opening Brief of DRA at 7.

[25] Joint Opening Brief of Demand Response Aggregators at 6.

[26] *Ibid*.

[27] Joint Opening Brief of Demand Response Aggregators, November 28, 2012 at 4-9.

6.1.2.2. Discussion

We affirm that in D.12-04-045, the Commission found that cost-effective demand response resources are an essential element of California's energy resource strategy. As a result, the Commission provided PG&E and SCE a choice to either renegotiate the current AMP contracts to ensure cost-effectiveness or perform a competitive solicitation for new contracts, maintaining at least the same level of MWs. However, in D.12-04-045, the Commission approved the solicitations, not the agreements themselves. While the Commission found the AMP program, itself, in compliance with other Commission decisions and reasonableness, exclusive of the cost-effectiveness issues, we did not make any such determination of the agreements in this proceeding because the proposed agreements did not exist. Furthermore, D.12-04-045 did not abdicate the Commission's responsibility, in § 451 or any other relevant code section, to ensure that the new agreements are just and reasonable and in the public's best interest. Therefore we must now review these agreements as we reviewed all programs in that decision, focusing on the issues of compliance with other Commission decisions, reasonableness, and meeting future needs.

6.1.3. Compliance with Prior Commission Decisions

6.1.3.1. Parties' Positions

In D.12-04-045, we required that all programs must comply with prior Commission decisions. The only point of contention regarding this issue focused on the Commission's Resource Adequacy decision, D.12-06-025. DRA argues that the PG&E agreements are not in compliance with D.12-06-025 that, as DRA states, requires that demand response resources must be capable of being dispatched by LCA by 2013 in order to receive local resource adequacy credit. DRA bases its contention on OP 10 directing that PG&E's AMP Program shall be counted for Resource Adequacy in the 2013 Resource Adequacy compliance year and that the AMP program must be locally dispatchable by May 2013.[28]

PG&E contends that DRA has misinterpreted the language in D.12-06-025. PG&E explains that a demand response program must be locally dispatchable in order to count for local resource adequacy credit.[29] PG&E further explains that not all of its service area is located in an LCA and is categorized as "Outside LCA." PG&E argues that if the Commission required that all demand response be locally dispatchable by LCA, this would prohibit these service areas from participating in demand response and qualifying for the Resource Adequacy program.

6.1.3.2. Discussion

We explained in D.12-06-025 that the Resource Adequacy program includes "system" and "local" Resource Adequacy requirements and utilities must "procure sufficient [Resource Adequacy] capacity resources to meet both obligations."[30] Furthermore, "local" Resource Adequacy requirements are based on the CAISO's Local Capacity Technical analysis allocated to each Load Serving Entity, each of which must procure sufficient resources in each Local Area in order to meet their obligation. We clarify here that, in OP 10 of D.12-06-025, our focus was to ensure that in order to count for *local* Resource Adequacy [emphasis added] a program must be locally dispatchable. In this application, PG&E has requested that those demand response resources that are locally dispatchable,

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[28] Opening Brief of DRA, November 28, 2012 at 8-9.

[29] PGE-01 at 1-6, lines 13-19.

[30] D.12-06-025 at 10.

and only those resources, be counted toward meeting local Resource Adequacy, as well as system-wide Resource Adequacy.[31]

NAPP argues that demand response resources that offer local dispatchability provide greater value than those that do not.[32] However, we reiterate that utilities are required to procure resources that meet requirements for both local and system wide resources. Thus, we find that PG&E's agreements that include demand responses resources without local dispatchability are in compliance with D.12-06-025.

No party disputed that the agreements requested by SCE are in compliance with prior Commission decisions. In our review, we find both SCE and PG&E's requested agreements to be in compliance with all prior Commission decisions, including D.12-06-025. However this application was filed following the submittal, by both PG&E and SCE, of their 2013 Resource Adequacy forecasts. Thus, PG&E and SCE shall file Tier 1 ALs, no later than 90 days from the issuance of this decision, to true-up prior Resource Adequacy credit changes for 2013 resulting from this decision.

6.1.4. Reasonableness

6.1.4.1. Parties' Positions

We have already determined that the Commission must find the agreements in this proceeding reasonable, pursuant to Pub. Util. Code § 415 and D.12-04-045. In D.12-04-045, the Commission examined the reasonableness of demand response programs in terms of not only cost-effectiveness and

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[31] *Ibid*.

[32] Reply Brief of NAPP at 3.

consistency with Commission policies (which we have previously discussed here), but also in terms of track record, future performance, cost, flexibility and versatility, adaptability, locational value, integration, simplicity and the recognition of environmental benefits. We review the AMP agreements with these aspects in mind.

PG&E points to several examples of why its AMP agreements are reasonable: 1) the agreements include an appropriate mix of local and system dispatchability; 2) the agreements provide significant Day-Of and Day-Ahead resources aligning with customer operations and the CAISO wholesale energy market requirements; 3) new operational triggers and required testing events provide assurances that the agreements will deliver load reductions in response to system or local conditions; 4) incentives will encourage load reductions during summer months; 5) aggregators are penalized for underperformance; 6) cost-effectiveness test ratio results meets the requirements of D.12-04-045; and 7) agreements align with Pub. Util. Code § 451 by providing a resource which is at the top of the loading order, increasing demand response resources from prior contracts, maintaining a viable aggregator community, and providing a necessary transition toward aggregator participation.

Noting that § 451 does not provide specific criteria for defining the justness and reasonableness of charges by a utility, ECS claim that D.12-04-045 established the following conditions for reasonableness: cost-effectiveness, track record, future performance, cost, flexibility and versatility, adaptability, locational value, integration, consistency across the Utilities' applications, simplicity, recognition, environmental benefits and consistency with general

Commission policies…" as well as CAISO market integration and demand response market competition.[33] Because these criteria were integrated into the Requests for Officers issued by the utilities, ECS contend that the agreements should be viewed as reasonable.[34]

Despite a firm opinion that the agreements only need to be cost-effective to be deemed reasonable, Demand Response Aggregators concede that another reasonableness consideration is the importance of these agreements in terms of a future investment in demand response. Demand Response Aggregators explain that because of significant unresolved questions regarding Third-Party demand response providers' participation in the CAISO's markets, D.12-04-045: 1) agreed to the merit of maintaining the AMP contracts during the transitional period and 2) rejected DRA's arguments that the contracts were not needed because they represented excess capacity.[35]

Relying heavily on the SCE agreements for comparison, DRA claims that ratepayers are at risk because the PG&E proposed agreements provide for only two test events for each contract year when SCE has negotiated an unlimited amount of test events. (DRA does not protest the SCE agreements.) Providing two scenarios where more than two test events are needed, DRA contends that two test events are insufficient and put ratepayers at risk to pay for capacity that has not been demonstrated to be available each month of the contract.[36] DRA requests that in order to find the PG&E agreements reasonable, the Commission

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33 Opening Brief of ECS, November 28, 2012 at 5.

34 *Ibid*.

35 Joint Opening Brief of Demand Response Aggregators, November 28, 2012 at 12-13.

36 Opening Brief of DRA, November 28, 2012 at 10.

should require PG&E to renegotiate the agreements and obtain at least four Test Events per contract year. DRA claims that this is reasonable given that SCE negotiated unlimited Test Events in its contracts.[37] DRA also requests that the Commission require PG&E to renegotiate the agreements to apply lower payments for low performance of any events. DRA explains that the PG&E agreements provide for lower payments to aggregators following test events where the aggregator underperformed but does not make the same requirement for underperformance during a non-test event.

In response to DRA's requested revisions, PG&E argues that neither revision is necessary. PG&E explains that the agreements already provide for under-performance by lowering performance payments and, in the case of very low performance, by requiring penalty payments to PG&E. Thus, PG&E contends that requiring contract negotiations for lower payments after non-test event under performance are unnecessary. Additionally, PG&E argues that by changing the event trigger for these programs, more operational events will be called, significantly lessening the need for additional test events. PG&E also points out that the Commission does not require more than two test events for the Demand Bidding, Base Interruptible or Capacity Bidding programs.[38]

6.1.4.2. Discussion

There is nothing in the record of this proceeding that leads us to increase the number of test events for the PG&E agreements. While we appreciate that SCE has been able to negotiate unlimited testing events with its Sellers, the

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[37] *Id*. at 12.

[38] PG&E Reply Brief, December 5, 2012 at 2.

scenarios that DRA described have not come to fruition over the history of the AMP program[39] and thus do not lead us to envision a need to require additional test events in the PG&E agreements. Because no other demand response program requires more stringent testing,[40] we find no reason, at this time, to require more than two test events for each agreement during each contract year.

However, we are concerned that, according to the October 2012 monthly demand response reports from PG&E and SCE, not one single test event was called last year for the AMP program.[41] While we acknowledge that more overall events were called for the AMP program during the 2012 season, we also recognize the importance of ensuring that the resources promised by the agreements are in place early in the season. Thus, to ensure that the Sellers are fully prepared to provide reliable demand response, we require that one test event be implemented near the beginning of each season, but no later than May 31. To ensure continued compliance by the Sellers, one additional test event must be implemented during the height of the season (i.e. July/August). If, however, the utilities dispatch these resources by July 15, no further test event is required.

In comments to the proposed decision, SCE noted that tests events can also be called by the Sellers, noting that test events are settled in precisely the same

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[39] Reply Brief of ECS, December 5, 2012 at 6.

[40] PG&E Reply Briefs, December 5, 2012 at 2.

[41] The monthly reports are provided to all parties of record in A.11-03-001 et al. and are available on the Commission website at: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Monthly+Reports/2012_DR.htm.

way regardless who calls them.[42] We find it reasonable to consider a Seller's test event equivalent to a utility-called test event. Thus, we clarify that a Seller's test event qualifies for the new test requirements if the associated utility treats the Seller's test events as they would its own test events. Furthermore, these test event requirements do not limit the number of additional test events that PG&E or SCE may schedule. Either utility may perform additional test events if they deem it appropriate.

We do not find it necessary to direct PG&E to renegotiate its agreements to require lower monthly capacity payments following low performance during a non-test event. We find that the payment structures in the proposed agreements provide the necessary incentives and penalties to assure compliance by the Sellers and reliability of the demand response. DRA's concern regarding a low performance can be resolved by either a retest[43] (in the case of a low performance during a test event) or a penalty paid to PG&E (in the case of a low performance during an actual event).

Under the terms of D.12-04-045 and Pub. Util. Code § 415, we find the proposed AMP agreements requested by PG&E and SCE, along with the new test event requirements, to be reasonable for providing a reliable demand response resource.

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[42] SCE Opening Comments to Proposed Decision, January 7, 2013 at 3-4.

[43] The Seller is required to pay for the re-test.

6.1.5. Meeting Future Needs

6.1.5.1. Parties' Positions

We have determined earlier in this decision that the agreements in this proceeding must be reviewed according to the same standards that we reviewed the applications in D.12-04-045, including meeting future energy needs. In D.12-04-045, we noted the evolving nature of demand response and the impact of its evolution on both current and future applications.[44] In that decision we looked at whether existing and proposed programs are sufficient to meet California energy goals in light of the changing nature of the energy grid and other specific activities such as the CAISO market integration and demand response market competition. We concluded that the "presence of third-party aggregators in California will foster the innovation needed to meet this approaching challenge."[45]

PG&E states that its local dispatch requirements reflect financial settlement methods similar to those required for bidding demand response resources into the CAISO market as Proxy Demand Resources and are thus moving toward the goal of CAISO market integration.[46]

In its protest to the applications, DRA recommends that rather than waiting for the CAISO markets to be ready for open bidding, the Commission should require both SCE and PG&E to "make as much progress in areas where such progress is feasible by 2014."[47] While DRA has since withdrawn its protest

[44] D.12-04-045 at 9.

[45] D.12-04-045 at 77.

[46] PG&E Opening Brief at 9.

[47] DRA Protest at 4.

to the SCE application, DRA continues to contend that the PG&E agreements that are not locally dispatchable, should not be approved by the Commission. DRA explains that the two products not locally dispatchable "do not add any value in meeting [the] Commission's goal to preserve current level of [demand response agreements] nor moves [demand response] in the direction of meeting [the] Commission's vision for future uses of [demand response]."[48] DRA contends that it is not reasonable for the Commission to allow ratepayers to pay for unnecessary agreements that are not responsive to future needs.

PG&E disagrees with DRA's recommendation to require PG&E to renegotiate contracts to meet future needs. In fact, PG&E argues that D.12-04-045 did not require that the agreements that are the subject of this proceeding must satisfy future CAISO market bidding requirements.[49] PG&E explains that future needs are to be addressed in Requests for Offers that take place after finalizing the direct participation rules and implemented new Resource Adequacy rules.[50] PG&E concludes that there is no intent by the Commission to address future needs in the 2012-2014 agreements. PG&E notes however that the new proposed agreements move the AMP program forward to meet future needs by having the local dispatch capability needed for bidding into the CAISO market.

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[48] Opening Brief of DRA at 15.

[49] PG&E Opening Brief at 11.

[50] *Id.* at 11-12.

6.1.5.2. Discussion

D.12-04-045 did not require either utility to design its AMP agreements to meet future energy needs. Specifically, D.12-04-045 says that "the Commission should preserve the [demand response] resources from current and future AMP contracts because they can be bid into the CAISO market."[51] Thus, it is the intent, but not requirement of the Commission, that the agreements in this proceeding move toward the goal of market integration given where the market is presently. We find that both PG&E and SCE succeeded in moving toward meeting future energy needs, albeit at differing degrees. Both utilities requested approval of contracts that procure resources above the current required floor and both have increased the resources available for local dispatchability. SCE went beyond the obligations of D.12-04-045 and required that all agreements be locally dispatchable at the Sub-Load Aggregation Point. While we commend SCE for going beyond the requirements, we recognize that, as PG&E pointed out in testimony, this approach is more costly and difficult to do.[52] We agree with PG&E that this set of agreements will afford us additional time and experience to move closer to the more granular approach as will be required by the CAISO market.

6.1.6. Outcome of the AMP Agreements Review

We find that all 10 SCE and PG&E AMP agreements meet the requirements of D.12-04-045 in that they comply with the cost-effective protocols approved in Decisions 10-12-024 and 12-04-045; they are reasonable including in

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[51] D.12-04-045 at 77.

[52] PGE-01 at 1-5 to 1-6.

terms of Pub. Util. Code § 451; they comply with other related Commission decisions, including D.12-06-025; and they move us toward meeting future energy needs. We approve the 10 AMP contracts requested by SCE and PG&E. However, we require the full implementation of a pre-season test event and a second high season test event, if necessary, as described above.

6.1.7. True Up with AL 4061-E/4164-E

Pursuant to D.12-04-045, PG&E submitted AL 4061-E, which contained resubmitted cost-effectiveness analyses of its Capacity Bidding and Demand Bidding Programs.[53] In AL 4061-E, PG&E proposed that certain costs associated with these programs be allocated to other demand response programs. In the Scoping Memo, PG&E was asked whether its proposed agreements have the higher costs referred to in AL 4061-E and whether those costs are reflected in this application.

PG&E explains that in the resubmitted cost-effectiveness analyses, the budgets for the Capacity Bidding and Demand Bidding programs decreased in turn decreasing the share of non-program-specific costs allocated to these two programs.[54] As a result the decreased shares of the non-program-specific costs shifted to the other demand response programs including the AMP program. In comments to the Proposed Decision, PG&E explained that Energy Division rejected AL 4061-E and directed PG&E to file another AL, 4164-E, with a

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[53] D.12-04-045 at OPs 44 and 50.

[54] Non-program-specific costs include Marketing, Education and Outreach; Evaluation, Measurement and Validation; System Support Activities, and Automated Demand Response costs and are allocated to demand response programs proportional to program budgets.

cost-effectiveness analysis that attains a TRC benefit-cost ratio of 0.9. PG&E states that the shifted costs denoted in both ALs were the same as those provided in the cost-effectiveness analysis included in PG&E's application.[55]

As we previously determined, the cost-effectiveness analysis for the agreements in this proceeding were performed accurately and consistent with the demand response cost-effectiveness protocols approved in D.10-12-024 and revised in D.12-04-045. Furthermore, we confirm that the analyses appropriately and correctly included the amounts of the non-program-specific costs shifted from the Capacity Bidding and Demand Bidding Programs.

6.2. Cost Recovery Issues

SCE requests authority to spend up to $49.3 million for the administration costs and capacity payments for its requested AMP agreements. SCE proposes to continue the same ratemaking methodology for these agreements that it uses in the current agreements. SCE also proposes to recover its revenue requirement through three balancing accounts: Base Revenue Requirement Balancing Account, Energy Resource Recovery Account, and the Purchase Agreement Administrative Costs Balancing Account.

PG&E requests the agreement costs for the AMP program, previously approved in D.12-04-045, continue to be recovered through its Energy Resource Recovery Account until the Commission addresses the allocation of demand response costs in the later phase of Rulemaking 07-01-041.

No party protests these requests.

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[55] PG&E Opening Brief at 13-15 and PG&E Opening Comment, January 7, 2013, at 3-4.

We find the proposed budget and cost recovery methodologies reasonable and authorize them.

6.3. SCE Tariff Changes

SCE requested authorization from the Commission to file a Tier 1 AL modifying its Demand Bidding Program to ensure that customers, wishing to enroll in both the Demand Bidding Program and an Aggregator program, understand that they will only get compensation for the Aggregator program. SCE explains that the Aggregator program is considered by the Commission to be a capacity program and pursuant to D.09-08-027, a customer enrolled in both programs will receive payment only under the capacity program. No party protested this request.

We find reasonable the request by SCE to revise its tariff for the Demand Bidding Program. We authorize SCE to submit a Tier 1 AL modifying its Demand Bidding Program tariff to include the following language: Effective no earlier than [the issuance of this decision], should a customer who places a Demand Bidding Program bid also be enrolled in a Demand Response Aggregator contract for the same month, the customer will not be given energy payments under the Demand Bidding Program tariff for load drops during coinciding or overlapping event hours between the two programs.

6.4. SONGS Mitigation

SONGS Unit 2, located in the service territory of SCE in Orange County, CA, has been non-operational since January 9, 2012 and Unit 3 has been non-operational since January 31, 2012. SCE requests that, in the event that the outage of the two SONGS units extends into the life of the proposed AMP agreements, the Commission authorize an expeditious review of a potential request to increase the Sellers' incentive payments for load drops from customers in the Orange County area. Specifically, SCE requests authorization to file a Tier 3 AL to modify one or more of the agreements to incorporate the proposed incentive increases. Furthermore, SCE acknowledges that the agreement revisions must continue to result in a cost-effectiveness analysis where the TRC ratio equals 0.9 or greater. No party protests this request.

In its Reply Brief, SCE announced that subsequent to the filing of its application, the Commission's Energy Director requested SCE to file a new application, no later than December 21, 2012, that would propose improvements and additions to SCE's current demand response programs to mitigate the effects of a continued SONGS outage. SCE contends that it is appropriate to include in the December 21, 2012 application, a proposal for providing additional incentives to Sellers for customer load drops in the Orange County area. SCE claims that no party will be prejudiced by having that proposal considered in connection with the December 21, 2012 application versus the Tier 3 AL requested in the AMP agreement application.

We agree that it is more appropriate to have any future changes to the AMP agreements approved today determined in the December 21, 2012 application instead of a Tier 3 AL. Thus there is no need to determine whether to authorize the filing by SCE of an expedited Tier 3 AL to address SONGS mitigation measures through the AMP agreements.

7. Motion of DRA

Pursuant to Rule 11.4 of the Commission's Rules of Practice and Procedure, DRA filed a motion on November 28, 2012 requesting the Commission for leave to file under seal the confidential version of its brief. DRA's brief contains information from the PG&E proposed demand response AMP agreements, designated by the Sellers as market-sensitive data. No party objected to the motion. In accordance with our Rules, we find the motion to be reasonable. We grant DRA's motion to file under seal the confidential version of its brief.

We affirm all other assigned Commissioner and ALJ Rulings, including e-mail rulings, in this proceeding. All motions not previously ruled upon or addressed in this decision are denied.

8. Comment Period

Pursuant to Rule 14.6(b) of the Commission's Rules of Practice and Procedure, all parties stipulated to reduce the 30 day public review and comment period required by Section 311 of the Public Utilities Code to 7 days with no reply comments. The proposed decision of the ALJ in this matter was mailed to the parties on December 31, 2012, in accordance with the above stipulation. Constellation New Energy, Demand Response Aggregators, DRA, Energy Curtailment Specialists, PG&E, and SCE filed comments on January 7, 2012. Additions and corrections have been made throughout the final decision in response to the comments received.

9. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Kelly A. Hymes is the assigned ALJ in this proceeding.

Findings of Fact

1. PG&E and SCE followed competitive solicitation procedures for the AMP agreements.

2. PG&E and SCE heeded Commission encouragement to seek additional demand response capacity beyond the floors required by D.12-04-045.

3. PG&E and SCE complied with the cost-effectiveness protocols first developed in D.10-12-024 and revised in D.12-04-045.

4. All 10 AMP agreements attained a TRC test benefit/cost ratio of 0.9 or greater.

5. All 10 AMP agreements meet the requirements of OPs 15 and 16 of D.12-04-045.

6. In D.12-04-045, the Commission approved the AMP solicitations, but not the AMP agreements.

7. In D.12-04-045, the Commission did not determine whether the agreements are in compliance with other Commission decisions, whether they are reasonable or whether they meet future energy needs.

8. D.12-04-045 did not abdicate the Commission's responsibility, in Pub. Util. Code § 415 or any other relevant code section, to ensure that the new AMP agreements are just and reasonable and in the public's interest.

9. In OP 10 of D.12-06-025, our focus was to ensure that in order to count for local resource adequacy, a demand response program must be locally dispatchable.

10. Utilities are required to procure resources that meet requirements for both local and system wide resources.

11. This application was filed after PG&E and SCE submitted their 2013 Resources Adequacy forecasts.

12. The test scenarios that DRA described have not come to fruition over the history of the AMP program and thus do not lead us to envision a need to require additional test events in the PG&E AMP agreements.

13. No other demand response program requires more than two test events annually.

14. There is nothing in the record of this proceeding that leads us to increase the number of required test events for the PG&E AMP agreements.

15. The October 2012 monthly demand response reports from PG&E and SCE show that not one single test event was called for the AMP program in 2012.

16. It is important to ensure that demand response resources promised by the AMP agreements are available and thus reliable .

17. Test events called by Sellers are equivalent to those called by the utilities, if the utility treats or settles the test events called by the Sellers in the same way as those the utility calls.

18. The payment structures in the proposed AMP agreements provide the incentives and penalties necessary to ensure both the compliance by the Sellers and the reliability of the demand response resources.

19. D.12-04-045 did not require either PG&E or SCE to design its AMP agreements to meet future energy needs.

20. In D.12-04-045, the Commission intended the AMP agreements to move toward the goal of market integration.

21. Both PG&E and SCE, to differing degrees, moved the AMP agreements toward meeting future energy needs.

22. SCE went beyond the obligations of D.12-04-045 by requiring AMP agreements to be locally dispatchable at the Sub-Load Aggregation Point.

23. Requiring resources to be locally dispatchable at the Sub-Load Aggregation Point may be more costly and difficult to implement.

24. This set of AMP agreements provide us additional time and experience to move closer to a more granular approach of local dispatchability that may be required in future CAISO markets.

25. The cost-effectiveness analyses performed by PG&E appropriately and correctly included the amounts of the non-program-specific costs shifted from its Capacity Bidding and Demand Bidding Programs to the AMP program.

26. No party protested the cost recovery requests for the AMP agreements.

27. No party protested the SCE request to revise its Demand Bidding Program tariff to ensure that customers, wishing to enroll in both the Demand Bidding and Aggregator programs, understand they will only be compensated for the Aggregator program.

28. It is more appropriate for SCE to address future changes to the AMP agreements related to the SONGS outage in its December 21, 2012 application instead of a future Tier 3 AL.

Conclusions of Law

1. The Commission should review the 10 PG&E and SCE AMP agreements in the same manner that we reviewed the demand response programs in D.12-04-045.

2. The Commission should review the 10 PG&E and SCE AMP agreements to ensure that they are just and reasonable and in the public's best interest.

3. The PG&E AMP agreements that include demand response resources without local dispatchability are in compliance with D.12-06-025.

4. The 10 SCE and PG&E AMP agreements are in compliance with all prior Commission decisions, including D.12-06-025.

5. SCE and PG&E should submit Tier 1 Advice Letters to true up their 2013 Resource Adequacy forecasts.

6. It is reasonable for the Commission to consider test events called by Sellers equivalent to test events called by the utility, if the utility treats or settles the test events called by the Sellers in the same way as the test events the utility calls.

7. The proposed PG&E and SCE AMP agreements are reasonable under the terms of D.12-04-045 and Pub. Util. Code § 415.

8. All 10 PG&E and SCE AMP agreements meet the requirements of D.12-04-045.

9. The Commission should approve the 10 PG&E and SCE AMP agreements for 2013-2014.

10. The AMP agreement budget requested by SCE is reasonable.

11. The cost recovery methodologies requested by PG&E and SCE are reasonable.

12. The Commission should approve the SCE budget of $49.3 million for the five SCE AMP agreements for 2013-2014.

13. The Commission should approve the cost recovery methodologies as requested by PG&E and SCE.

14. The SCE request to revise its Demand Bidding Program tariff is reasonable.

15. The Commission should approve the SCE request to revise its Demand Bidding Program tariff.

16. DRA's motion to file under seal the confidential version of its brief is reasonable.

17. The Commission should approve the Motion by DRA to file under seal its confidential brief.

O R D E R

IT IS ORDERED that:

1. The five agreements between Southern California Edison and demand response aggregators to provide the Aggregator Managed Portfolio program during 2013 and 2014 are approved.

2. A budget of $49.3 million is authorized for the Southern California Edison demand response aggregator managed portfolio program during 2013 and 2014.

3. The five agreements between Pacific Gas and Electric Company and the demand response aggregators to provide the Aggregator Managed Portfolio program during 2013 and 2014 are approved.

4. Pacific Gas and Electric Company and Southern California Edison must submit a Tier 1 Advice Letter within 90 days of the issuance of this decision to true up their 2013 Resource Adequacy forecasts.

5. Pacific Gas and Electric Company and Southern California Edison are required to perform a demand response test event early in each contract season, but no later than May 31. A Seller's test event meets this requirement, if the utility treats or settles the Seller's test event equivalent to the utility test event.

6. If Pacific Gas and Electric Company and Southern California Edison Company have not dispatched any Aggregator Managed Portfolio program resources by July 15 of a contract year, each company is required to perform at least one other test event by the end of August of that year. A Seller's test event meets this requirement, if the utility treats or settles the Seller's test event equivalent to the utility test event. Nothing in this decision precludes either utility from performing additional test-events.

7. The cost recovery methodologies requested by Pacific Gas and Electric Company and Southern California Edison Company are approved.

8. Southern California Edison Company must submit a Tier 1 Advice Letter revising its Demand Bidding Tariff to ensure that customers dually enrolled in the Demand Bidding and Aggregator Managed Portfolio programs understand they will only be compensated for the Aggregator Managed Portfolio program resources.

9. The Motion of the Division of Ratepayer Advocates requesting the Commission for leave to file under seal the confidential version of its brief is granted.

10. Applications 12-09-004 and 12-09-007 are closed.

This order is effective today.

Dated ______________________________, at San Francisco, California.